BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates

Docket 3270-UR-120

DIRECT TESTIMONY OF WILLIAM B. MARCUS
ON BEHALF OF CITY OF MADISON

I. Introduction

Q. Please state your name, business affiliation and address.

A. My name is William B. Marcus. I am Principal Economist for JBS Energy, Inc., 311 D Street, West Sacramento, California 95605.

Q. Please provide your qualifications.

A. My qualifications are attached as exhibit Ex.-City of Madison-Marcus-1. I have over 36 years experience with energy utility issues. I have previously testified or made formal comments before about forty federal, state, provincial, and local utility and environmental regulatory bodies in the U.S. and Canada on issues including utility restructuring and performance-based ratemaking, revenue requirements, resource planning, and cost-of-service and rate design.

Q. Have you previously filed testimony in Wisconsin?

A. Yes. I filed testimony on cost allocation and rate design in March, 2000 in Docket No. 6630-UR-11 a case involving Wisconsin Electric Power Company. I was not cross-examined in that docket.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the City of Madison. I was retained to review cost allocation and rate design issues in this application by Madison Gas and Electric Company ("MGE" or "the Company"). In particular, I am reviewing MGE's request to raise the customer charge to $19 in this rate case and its underlying policy supporting even more massive increases to $48 in 2016 and $69 in 2017 and to institute optional residential demand charges (which have been shelved temporarily) as well as similar proposals for the small commercial class.

Q What do you recommend?

A I recommend that the Commission use the three cost studies that I have prepared as "bookends" for cost allocation, placing more weight on the cases without a minimum system, and on the TOU case (which assigns 60% of baseload plant as related to energy). I also recommend that the Commission either not raise the residential and small commercial customer charges, or, in the alternative raise them by no more than the rate by which residential rates are raised.

Finally, I recommend that the Commission give guidance that it will not entertain the massive increases to residential and small commercial customer charges that the Company's policy dictates in 2016-2017 based on the inclusion of demand costs in customer charges. In the residential class, MGE has made deliberate choices to make people with low loads, poorer people, and people in apartments, cross-subsidize people with higher loads, richer people, and people in single-family homes. Optional residential demand charges are no better, because they often have very low coincidence with the demands that cause the utility to avoid generation, transmission, and distribution costs.

In the small commercial class, the Company is deliberately choosing to make the smallest businesses, using single-phase power, subsidize larger businesses with higher demand and far more expensive three-phase hookups. Both of these choices are "Robin Hood in reverse:" charging low users more than the utility knows it costs to serve them, to subsidize bigger customers.

II. Cost of Service

A. Generation Cost Allocation

Q. How has MGE allocated generation plant costs?

A. It has allocated them by coincident peak demand over the twelve months of the year (12CP). For the information of the Commission, it provided an allocation method that has been provided in the past, which allocates 60% of costs based on energy (peak period energy in its analysis) and 40% of costs based on 12 CP. However it specifically states that it does not agree with this method, even as a "bookend" to analysis. It has provided an alternative single-month coincident peak (1CP) at the request of Airgas, its largest customer.

Q. How does the allocation translate into rate design for residential and small commercial customers?

A. In 2015 rates, the costs remain as part of the energy costs, but MGE originally proposed to place all of the demand-related costs in customer costs in 2017 and moves toward that direction in 2015 and 2016, with optional residential and small commercial demand charges.

Q. Why is it important to consider this allocation carefully?

A. The first reason is class allocation. The second is that if a portion of generation costs are assigned to energy (as in MGE's time of use –TOU - allocation) then the residential and small commercial classes are assigned less costs. This makes sense, in that the relatively high fixed costs of baseload powerplants reduce the cost of energy. The second issue is that if the cost of baseload powerplants end up being shoved into customer charges or demand charges under MGE's ultimate rate design policies that it wants to pursue in future cases, the new design will result in huge cost shifts which are unwarranted under cost of service principles.

Q. What are the reasons for the construction of generating plants?

A. The "need for generation" essentially must be broken down into two separate questions. The first is how much generation is required. The second is what kind of generation is required, because there are a variety of generating technologies with varying capital costs. Generation with lower capital costs tends to have higher variable costs, such as fuel, and vice versa.

Q. What are the causes for need for a specific amount of generation?

A. The amount of generation is generally calculated based on meeting the system coincident peak load with a reserve margin adequate to cover periods of system stress caused by generating plant outages. System stress does not just occur in the peak hour of the year but can occur in a considerable number of hours when loads are high. Stress can occur even in non-peak months when large generating plants are taken down for maintenance and there is the potential for other units to then suffer forced outages. Thus it is reasonable to assume that the need for generation is caused by a number of high-load hours which are broader than the single coincident peak hours. In this regard, a 12CP allocation method is reasonable.

Q. Do energy requirements explain why specific types of generation are built?

A. Yes, the choice of generating plants is generally based on attempting to minimize total system costs taking into account fuel costs, fuel diversity, and sustained energy use, while maintaining reliability, responding to uncertainties, and meeting constraints caused by generation lead times. There is a significant energy-related component to the choice of what to build. If a utility is building a plant that provides energy in a few hours at peak or for reserves, it builds a peaking plant – low capital costs, high fuel costs. If a utility needs energy around the clock, it builds baseload generation – much higher capital costs, much lower fuel costs. For intermediate loads, the utility builds a plant such as a combined cycle, which has capital costs and fuel costs between the peaker and the baseload plant.

Q. What part does fuel mix play?

A. Utilities also make choices of what to build based on fuel diversity as well as absolute fuel costs, and choose a diverse mix of fuels in order to hedge against both price and environmental risks associated with overconcentration in specific fuels. One of the means of maintaining fuel diversity is to acquire power from renewable resources, either by purchase or ownership. Most renewables share characteristics with baseload resources, high capital costs and zero or low fuel costs.

Q. Are generating plant costs entirely caused by peak loads?

A. The clearest examples explaining why generating plant costs are not entirely caused by peak loads come from units with extremely low fuel costs – nuclear, hydro and wind.

For example, MGE has 51 MW of utility-owned wind power. A utility will spend the capital to build wind generation to save fuel and gain environmental benefits that are entirely related to the energy that the plant produces. Wind energy has limited firm capacity per unit of energy but provides energy with low variable costs and no fossil fuel use when the wind is blowing. The intent when the plants were built was clear – they were built to save expensive fuel and provide diverse fuel sources. The meeting of peak load remains an incidental consideration.

Q. Do any other Wisconsin utilities classify a significant portion of generation costs to energy?

A. Yes. In both its Wisconsin and Michigan jurisdictions, Northern States Power uses an average and peak method (where generation is classified such that a percentage equal to the load factor is multiplied by average demand or energy; while the remaining costs (one minus the load factor) is multiplied by peak demand. Exhibit Ex.-City of Madison-Marcus-2 provides an excerpt from testimony provided by NSP before the Minnesota Public Utilities Commission that provided a very good description of generation cost allocation methods in its jurisdictions.

The TOU method that MGE offers, but specifically rejects in this case, is quite similar conceptually and in result to NSP's average and peak method, except that it is not applied to generation other than steam generation.

Q. What is your recommendation?

A. I recommend that the Commission continue to examine both MGE's 12CP method and the TOU method after correcting both of the methods as discussed below, but that it should give greater weight to the TOU method, which assigns significant baseload power costs to energy, than to the Standard Method. The energy allocation reflects why baseload plants and windmills are chosen instead of a system with more peakers.

Q. Do either the Standard (12 CP) or the TOU methods require corrections?

A. Yes. Both methods should classify wind generation to energy because it has a very limited capacity credit, should classify rail cars to energy, and should classify fuel costs of peakers to peak period energy rather than demand. In addition, there is an issue related to the Elm Road and West Campus plants. Their return and depreciation are included in FERC Account 507 (rents). The rental O&M expense is mis-classified as entirely demand-related in the TOU study, even though it covers return, taxes, and depreciation for coal-fired generation, which should be partially assigned to energy.

Q. Will you discuss the wind issue?

A. On the system of the Midcontinent Independent System Operator, wind energy has a capacity credit which varies by wind farm but is on the order of only 15% of the nameplate capacity (as indicated in testimony in both Northern States Power in Minnesota included in exhibit Ex.-City of Madison-Marcus-2 and MidAmerican Energy in Iowa). It also has zero fuel costs and a production tax credit that is credited back to customers based on energy. Wind plant is not built to meet capacity needs. An energy classification of wind is therefore reasonable, regardless of how the rest of the system is classified and allocated.

Q. Please explain the classification of rail cars?

A. Rail cars owned by MGE should be classified as energy-related. Rail cars are not owned, leased, or used to meet peak demand. Rather they are acquired in sufficient numbers to deliver coal to the plant’s coal inventory pile on a sustained basis. They are not sized for peak. The coal burned at a power plant is obviously energy-related. Similarly, rail cars are energy-related because there would be no coal to burn without the rail cars. MGE owns $2,015,000 of net plant in rail cars in the test year (MGE Response to Madison Data Request No. MAD-116, PSC REF#: 213831). MGE allocates the entire cost of some rail cars that it leases as energy-related (Id.). But the return on the cars it owns, illogically, is a fixed cost and treated as demand related. Rail cars serve the same function whoever owns them. They should not suddenly become demand costs just because the company owns them instead of leasing them. The return and depreciation on rail cars along with some small amounts of plant-related A&G expenses and property taxes, should be treated as an energy-related base rate cost to put all coal transportation on the same basis for cost allocation.

Q. Will you explain the peaker fuel issue?

A. MGE classifies the fuel costs to run peaking units as demand-related. I classify them using MGE's E12 allocation factor (peak period energy). Fuel costs do not vary by peak demand. They vary as the plants are used. I do believe it is reasonable to classify these costs only to peak hours, since the plants run rarely off-peak, even in the Standard analysis without TOU considerations.

Q. Will you discuss the classification and allocation of FERC Account 507 (Rents) in the TOU study?

A. As explained in MGE Energy's annual 10-K reports to the SEC, MGE's portion of the Elm Road coal plant is leased to it by MGE Energy, and MGE's portion of the West Campus Cogeneration Facility (WCCF) is leased to it by MGE Power West Campus. Exhibit Ex.-City of Madison-Marcus-3 contains an excerpt from these reports. These costs are contained in FERC Account 507. In the TOU study, all costs in this account are treated as demand-related, even though costs of steam plant directly owned by MGE are treated as 60% energy-related and 40% demand-related. In the context of the TOU study, this treatment is inconsistent and erroneous. I therefore classify it to both demand and energy in my version of the TOU study.

B. Distribution Cost Allocation

Q. What is the key issue of distribution cost allocation in MGE's cost of service?

A. The key issue is whether to classify costs between customer and demand costs based on a minimum system or not.

Q. What has MGE proposed?

A. In conducting its cost-of-service study, MGE proposes to allocate distribution system costs, which are a significant component of the bills paid by smaller customers, using the "minimum system method". MGE posits that there is a minimum size distribution system that would provide service to all customers, equally. The cost of this "minimum system" is classified as a customer-related cost (Direct-MGE-Trinh-4, PSC REF#: 205597). Where the minimum system was not sufficient to serve a customer's or customer class's demand, the additional cost of distribution to serve those customers is classified as demand related.

More concretely, as shown in the tabs attached to its cost of service study (MGE Response to PSCW Staff Data Request CSS-3 (1), PSC REF#: 214319), MGE proposes to design a minimum system that can serve each customer with approximately 1.09 kW of demand (based on 35-foot poles, a relatively small size wire, and 1 kVa of transformer capacity) per customer. The remainder of the system is demand-related, but demand is calculated by subtracting 1.09 kW of demand from each customer, thus reducing the demand of classes containing smaller customers and assigning more of the remaining costs to the classes with larger customers. In addition, MGE assigns underground system costs to classes on a demand-related basis after directly assigning the underground system to the customers in specific areas.

Q. Will you comment on the minimum system?

A. In the case of MGE, the largest effect of the minimum system is on rate design rather than cost allocation, because MGE actually subtracts demand carried by the minimum system (following an argument made over 30 years ago by George Sterzinger, in a July 1981 article in Public Utilities Fortnightly entitled "The Customer Charge and Problems of Double Allocation of Costs") in its cost allocation process. Nevertheless, the assumptions that underpin the minimum system method are faulty.

First, it equates the costs of spanning the system's area with customer costs. However, this is a leap of faith. The correlation between area and the number of customers is relatively weak (except in uniform and highly rural service areas). More importantly, if one could hypothesize such a concept as serving customers without a significant demand, the area would not be served at utility expense. Most utilities' line extension rules provide that service is extended at utility expense based on the revenue to be generated from that service (either explicitly or implicitly - as with a dollars-per-customer allowance based on class average revenue). If revenue is not adequate, service is only extended at the cost of the applicant. If a customer wanted access to the system but did not have any demand, they would have to pay for that access under typical line extension rules, rather than having the cost picked up by other ratepayers. Thus, fundamentally, the expansion of the distribution system as it is actually built is driven by demand, not the mere existence of customers.

Second, assignment of an equal amount of the minimum system to each individual customer makes no sense. On the MGE system, each customer served at primary voltage is assigned 87 feet of primary conductor and each customer served at secondary is assigned 60 feet of secondary conductor. Each customer except the few served exclusively at primary is also allocated the cost of 0.29 35-foot poles. These figures are based on the Cost of Service Model, “Conductor Footage” and “Poles” tabs (MGE Response to PSCW Staff Data Request CSS-3 (1), PSC REF#: 214319). The amount of conductor has since increased so the amount of conductor footage per customer is now higher than this figure by some amount, but the customer component continues to allocate an equal number of feet per customer.

A store with street frontage on an entire block would clearly need more feet of wire (and more poles if served from overhead) to connect it than would each of (for example) 50 individual residential customers in an apartment building on the same sized block. Yet each apartment dweller would be assigned the same portion of the minimum system as the large building, not one-fiftieth as much.

Thus a significant failing of the minimum system is the systematic overcharging of people who live in apartments, who are cheaper to serve because they are more densely packed (thus needing less primary voltage line to be connected to the system), share transformers and have much shorter runs of secondary and service lines. Customer costs (and customer charges if based on those costs) should be lower for apartment dwellers. Given that people living in apartments tend to have lower incomes than people living in houses, as discussed below, the end result is that the minimum system causes the poor to subsidize the rich.

A related failing of the minimum system can be examined when we look at a primary distribution line connecting two towns in a rural area of the system. That line is necessary to serve demand in those communities. The same connection would be needed just as much if there were one industrial customer located at the connection point with a demand equal to the whole town's demand as if there were 1,000 residential and small commercial customers. Yet the minimum system method would charge the hypothetical large customer 0.1 % as much as the hypothetical 1,000 town residents for the "customer-related" portion of the same line.

There is a third problem where the minimum system can double-count the costs of serving low-use customers, both across customer classes for cost allocation and within customer classes if used for rate design. But this is the only problem that MGE addresses. In a nutshell, this third analytical problem arises because the minimum system method develops a hypothetical utility system made up of poles, wires, and transformers that can carry a significant amount of demand. The minimum system is assigned to all customers as equal dollars per customer. If that is done, then it is wrong to allocate the remaining demand related portion of the system by the total system demand. Analytically, if the minimum system is used as a customer cost, it would be necessary to use a demand allocator that would give each customer class credit for that portion of the demand (an equal number of kilowatts per customer) that can be carried by the minimum system. MGE does that.

My views on this topic are by no means new or path-breaking. Serious critiques of the minimum system method date back over 50 years. Professor Bonbright recognized the inaccuracies of treating minimum system costs as customer costs in his 1961 edition of Principles of Public Utility Rates (exhibit Ex.-City of Madison-Marcus-4). Although the latest edition, revised by others in the 1980s after his death, omits this criticism, the preferred option of the live Mr. Bonbright was to recognize that minimum system costs were neither demand nor customer costs but were unallocable. He adds:

> And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that "the sum of the parts equals the whole." He is therefore under impelling pressure to "fudge" his cost apportionment by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.
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> (Bonbright, pp. 348-349)

Q. Are there alternatives to the minimum system method used by MGE?

A. Yes. There is a "zero intercept method" which uses regression equations to determine the cost of a zero-amp conductor or a zero-foot pole. In these cases, the minimum system would carry no demand and demand would not be subtracted. It generally produces lower customer percentages than the minimum system method. In the specific case of MGE, the costs under the zero intercept method for poles and conductors are not significantly different from zero, thus suggesting that all costs are demand-related and none should be charged on the basis of customers, as MGE has done. Exhibit Ex.-City of Madison-Marcus-5 contains data supporting the treatment of poles and conductors as entirely demand-related using a zero-intercept method, as calculated from MGE Response to City of Madison Data Request No. MAD-61 through MAD-63 (PSC REF#: 214081, 214082 and 214085 respectfully). This finding supports our position that the minimum system method is not reasonable.

Q. What do you recommend?

A. I recommend that the minimum system method be rejected for purposes of rate design, as it has too many problems, even as implemented by MGE with a demand offset, particularly as related to multifamily residential customers, of which there are many in Madison. My "bookend cost of service" removes it for purposes of examining cost allocation, although there is very little impact on the allocation among customers in the class cost of service.

Q. If the Commission were to adopt MGE's minimum system method, are there any errors that should be corrected?

A. Yes, if one were to accept the MGE method, corrections are needed for poles, conductors and transformers.

Q. Will you describe the errors related to conductors?

A. For conductors, MGE has not used its lowest cost conductor in common use (what should be a minimum-system), but has instead used a conductor of larger size and higher ampacity. The higher cost conductor it used is a No. 4 BHD conductor with a cost of 16.07 cents per foot and a capacity of 185 amps. However, there are over 1.2 million linear feet of No. 6 Poly conductor with a cost per foot of 11.22 cents and a capacity of 120 amps. This should be the minimum system.

In addition, a number of conductor sizes are cheaper than the minimum conductor. The Company's mechanical calculations assume that these conductor sizes actually have a customer component in excess of 100% because they are not as costly as the minimum system.

When these two items are corrected, the customer component of conductor falls from 9.57% to 6.64%.

Q. What is the problem with poles?

A. I believe that a 35-foot wood pole would be reasonable in the context of a minimum system carrying about 1 kW of demand, but again, the Company has incorrectly assigned a customer cost in excess of 100% to poles smaller than 35-feet, which needs to be corrected. Correcting that error reduces the customer percentage for poles from 37.15% to 36.33%.

Q. What is the issue with transformers?

A. MGE assigned each customer 1 kVA of the embedded cost of transformers including capacitors and regulators. Capacitors and regulators are assigned to all customers because they regulate voltage and reduce losses and are not part of the minimum system. Excluding capacitors and regulators reduces the cost from $31.77 per kVA to $31.06 per kVA, reducing the minimum system cost from 7.21% to 7.05%.

Q. How have you reflected these issues?

A. In my bookend cost of service studies based on MGE's filing with the minimum system, I have corrected these errors.

C. Other Cost Allocation Issues

Q. Have you identified any other problems relating to MGE's cost of service study?

A. Yes. The customer weighting for customer service (allocator "cwcs") assigns too many costs to residential customers. The weighting is based on costs in FERC Accounts 908-910 (customer service and information). Accounts 909 (advertising) and 910 (miscellaneous costs) are allocated by number of customers. Account 908 (which includes energy efficiency, major account representatives, and other costs) is assigned by a different weighting that allocates costs more broadly, with a much larger allocation to business customers. MGE has based its weighting on $1,725,000 in Account 908, $140,000 in Account 909, and $220,000 in Account 910. (MGE Response to PSCW Staff Data Request CSS-3 (1), PSC REF#: 214319, "Cust Alloc" spreadsheet. Figures rounded to nearest $1,000 for exposition.) However, the revenue requirement in the COSS is $6,938,000 in Account 908 and $381,000 in Accounts 909-910. (Id. at "Other OM" spreadsheet .) Using the higher figures for Account 908 produces a different allocation than MGE proposed, as shown in exhibit Ex.-City of Madison-Marcus-6.

Q. Do you have any other changes to the cost of service model?

A. The numbers will be different for some cost categories (administrative and general, materials and supplies, distribution O&M). However, those differences flow through from all the changes discussed above and do not involve any additional differences in methodology between my analysis and the Company's.

D. Summary of Results

Q Have you summarized your results?

A Yes. There are three summary schedules in exhibit Ex.-City of Madison-Marcus-7. These are the "bookends" that we have prepared. The first two are similar to MGE's "Standard" and "TOU" cost studies, except that they contain all of the corrections identified above. The third is the "TOU" cost study, with the minimum system replaced with an all-demand allocation method for Accounts 364-368. This is the study that I believe deserves the most weight, but I am providing all of them for the Commission's information.

Exhibit Ex.-City of Madison-Marcus-8 shows the "bookends" among the studies. The point is that the corrections made in this testimony (technical corrections to minimum system numbers, weighting of customer services, wind and rail cars as energy-related, and in the TOU study, allocating rents of WCCS and Elm Street to both demand and energy) reduce the General Service allocation by 0.73% in the standard cost study and by 1.04% in the TOU cost study. The TOU reduction is greater because it is the only one that needs to correct the error in calculating rents. The use of an all-demand cost allocation actually gives a higher cost allocation for general service than the minimum system, because of MGE's reduction in demand by 1.09 kW per customer for the demand carried by the minimum system.

In other words, without the minimum system changes that I recommend, general service rates should be between 0.73% and 1.04% less than MGE's request.

We would propose a rate spread that starts with averaging our three bookends 1, 2, and 3, the standard and TOU cases and the middle case of the TOU without the minimum system. The general service rate group receives a reduction of 1.04% from MGE's proposed rates assuming the same revenue requirement, and residential customers receive a reduction of 1.19% from MGE's proposed rates.

III. Rate Design – Customer Charges

A. Customer Impacts

Q. Have you examined customer impacts associated with MGE's proposal?

A. Yes. They are quite large in this rate case, and the direction in which MGE wants to go by 2016 and 2017 can only be categorized as extreme. See exhibit Ex.-City of Madison-Marcus-9 which shows MGE's current 2015 proposal and the implications of its policy for 2016 and 2017 where the customer charge would rise to $49 and then $69 in approximate terms.

Customers who use half as much as the average MGE customer will receive increases of about 11% in 2014 (compared to a 3.3% system average increase), while customers using twice as much as average will receive rate decreases of 1.5%. 34% of MGE's customers will have increases that are more than 5% above the class average increase, while the largest 16.5% of customers will receive actual rate decreases. The top 0.7% of MGE's customers will receive a rate decrease of $193 apiece under MGE's proposal.

Q. Is this the end of it?

A. By all means no. While MGE may have delayed full implementation of the policies behind the proposed 2016-2017 rate design changes, MGE has provided no indication that it does not intend to pursue those policies in the future, with the devastating results I discuss. We have therefore analyzed the 2016-2017 rates that it originally requested to show the policy direction where MGE wants to take us.

Under MGE's original proposal, 47% of customers would receive increases of about 12% or more, and 34% of its smallest users would be charged over $100 more per year. Their electric bills would rise by $99 million from 2014-2016! While 42% of MGE customers would see rate decreases, the lion's share goes to the top 15%, who would see their rates drop by an average of $520 per year ($118 million) from 2014 to 2016. The top 4% would get rate reductions of $906 apiece ($53), while the top 0.72% would get $1,304 apiece in savings (a total of $13.8 million).

The 2017 rate increase, which MGE dropped even earlier, would have set a customer charge of $68.53, charging customers $821 per year just to be connected to the system. The one third of lowest users would pay at least 40% ($278) more per year, with customers using half as much as the average paying $342 more. The one-third of lowest users would pay $206 million more in MGE's proposed 2017 rates. Meanwhile rates would be reduced by as much as 55% for the top 0.72%. The top 15% would have rate decreases by an average of $886 per year ($170 million) from 2014 to 2017. The top 4% would get rate reductions of $1,582 apiece ($92 million), while the top 0.72% by themselves would get $2,301 apiece (a total of $24.2 million).

B. MGE's Customer Charges Are Not Cost Based

Q. Do any of MGE's proposals, particularly its policy direction beyond 2015, have anything at all to do with cost of service?

A. Absolutely not. MGE takes all charges that are not classified to energy and charges them out in equal dollars per customer. This is especially problematic with demand costs. In reality, demand-related costs vary with the size of the customer, they are not equal for all customers in a rate class. Bigger customers use more of the system peak period energy and system demand and cause more of the costs, pure and simple.

Q. What does Mr. Bollum say about this?

A. He minimizes the problem and mixes up customer maximum demand with system coincident demand. He says:

> Unlike larger commercial or industrial customers where demands can vary from as little as a few kilowatts to as much as several megawatts, the peak demand for these small customers generally does not vary by much. The maximum annual demand for a residential customer, for example, does not vary by plus or minus a couple kW from the 4.6 kW non-coincident class average. Consequently, the demand-related distribution cost for most residential customers currently is roughly comparable and does not vary significantly with the level of monthly energy use. (Direct-MGE-Bollum-9, PSC REF#: 205588).

Mr. Bollum claims that "a couple of kilowatts" simply comes out in the wash, and that an apartment dweller who uses say 4 kW less than a large single-family home owner (2.6 kW vs. 6.6 kW – plus or minus a couple of kW) should pay the same amount as the large single-family home owner. He doesn't care that the apartment dweller (if not served by off-peak electric heat) is responsible for 39% as many demand costs as the owner of the big house – in his own "plus or minus a couple of kilowatts" analysis. The Company doesn't know if the apartment dweller is cheaper to hook up. (MGE Response to City of Madison Data Request No. MAD-96, PSC REF#: 214259), even though a number of other utilities know that apartment hook-ups are cheaper than single-family hook-ups, and the State of Nevada even has separate rate classes with lower rates for apartments than for single-family houses. Thus, even if we accept Mr. Bollum's premise, which I do not, he is deliberately and knowingly overcharging small users, because it isn't worth bothering to get it right. Exhibit Ex.-City of Madison-Marcus-10 contains an analysis provided by MGE (part of the response to City of Madison Data Request No. MAD-92, PSC REF#: 214095) showing lower use in multi-family than single-family homes, lower use by renters, and lower use in dwellings with fewer square feet. The Company's long-term rate design policy is to demand that seniors on fixed incomes in apartments, which are cheaper to hook up and use less demand (particularly diversified on a system basis), subsidize mansions.

When MGE moves on to include generation and transmission in the customer charge (the 2017 rate) it gets even worse. Customers who use lots of peak power are given a break, while customers who use little peak power pay even more to subsidize the large users. Essentially this is a clear wealth transfer without any basis in cost from (a) people without air conditioners to people with air conditioners, (b) apartments (which have lower peak demands because of smaller sizes and common walls) to single-family residents, and (c) smaller dwellings to bigger dwellings.

Q. Will you comment on Mr. Bollum's assumption that non-coincident demand by the customer drives distribution demand, which leads him to use distribution customer charges for demand-related costs?

A. The Company refused to allow us to test Mr. Bollum's theory, because it objected to and refused to respond to City of Madison Data Request No. MAD-39, because it claimed that this was part of its withdrawn demand charge proposal. (MGE Response to City of Madison Data Request No. MAD-39, PSC REF#: 215870.)

In the absence of MGE data, we turn to data from Southern California Edison, as they have done extensive analysis on this issue. That utility found that the coincidence is relatively low. Edison finds coincidence with distribution loads of 35% for single-family customers and 26% for multi-family customers. It is even lower for apartment dwellers than people living in single-family houses. Exhibit Ex.-City of Madison-Marcus-11 contains some of Edison's findings and analysis.

Q. Will you comment on customer acceptance of residential demand charges?

A. Acceptance of short-duration demand charges is questionable. Very short period demands essentially force perfection on customers in managing all aspects of their loads. An analysis was conducted by the Ontario Energy Board with residential focus groups. The conclusions reached by the focus groups reflected concerns about maximum usage charges in addition to TOU rates that customers understand:

> The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.
>
> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption. (Gandalf Group, Ontario Energy Board Distribution Charge Focus Groups: Final Report, October 9, 2013, p. 9)

C. Customer Charges will Harm Lower Income Customers

Q. Will you discuss the relationship of electric use and income?

A. National and regional data (from surveys done by the Bureau of Labor Statistics "BLS") indicate that lower income people use less electricity. Exhibit Ex.-City of Madison-Marcus-12 contains the most recent 2013 data. For example, the BLS Consumer Expenditure Survey for 2012 (national and midwestern region) shows that electricity expenditures of those earning over $70,000 are approximately double those of those earning less than $10,000 in both the national and midwestern regional data. There are no regional data above $70,000, but national data shows that electricity spending by those earning over $150,000 is 2.35 times that of those earning from $5,000 to $10,000.

Q. Does MGE obtain similar results to this national data?

A. No, according to MGE Response to City of Madison Data Request No. MAD-92 (PSC REF#: 214095). However, the results that MGE provides in MAD-92 are contradictory. Electricity use is allegedly not correlated with income at all, even though electricity use is lower for all sorts of housing and demographic conditions that are fairly strongly correlated with income (e.g., lower in apartments, duplexes, and townhouses, lower among renters, much lower in dwellings with fewer square feet). Therefore, I am not placing large amounts of weight on MGE's results claiming that income and usage are not related, given that those results contradict both national and regional income data as well as MGE's own data on other usage drivers related to the housing stock.

D. Energy Efficiency

1. Fixed Cost Rate Design is Based on a Theory that Markets are Efficient. Energy Efficiency Policy is Based on the Known Reality that Markets are Inefficient.

Q. What are the policy impacts of higher customer charges and fixed charges in electric utility cost recovery?

A. MGE's economic efficiency argument is oversimplified, and the impacts of increased fixed charges do not necessarily include more efficient customer decision-making. While MGE's argument appears to be based on economic principles, high fixed charges fail to promote economic efficiency as they provide ratepayers with little information about the costs that they are imposing on the system. This leads to uneconomic levels of consumption.

This is the kind of abstract argument that a market-oriented economist would make without looking at the real world. Many economists assume that the world runs like a Swiss watch without market imperfections. If we just "get the prices right" consumers will "do the right thing." Under this view, there is allegedly no reason to encourage conservation *or distributed renewable generation* unless one is concerned about global warming, as state commissions should be, or depletion of natural resources.

High fixed charges reduce incentives for customers to conserve energy *or use renewable sources to generate their own* by reducing the payback on investments in efficient appliances *and generation*. They also reduce the ability of customers to control their own bills through their own consumption decisions. But in the narrow economic view I am describing, whatever customers do in response to price is deemed to be economically rational, so we ought to send the "right" signals.

The Commission knows that this view of the world is not true; otherwise it would not be allocating significant ratepayer money to offer expanded energy efficiency programs.

This view also overlooks significant institutional barriers that prevent cost-effective efficiency investments from occurring. These include but are not limited to:

- split incentives (where one party pays for the investment and the other pays the utility bill), such as between landlords and tenants and similarly between new home builders and the first owners;
- tenure versus appliance life (a residential customer may not believe that he or she can gain adequate benefits from an investment if the length of residency is short or uncertain), even though future customers who occupy the premises would receive benefits over the life of the investment;
- lack of information by customers on investment choices with different energy use, their effectiveness, and their impact on energy costs;
- lost opportunities (conservation investments that must be made at a particular time, when a building is built or an appliance is replaced).
- lack of capital to spend on efficiency investments.
- The fact that carbon emissions are unpriced in cost of service study, even though, as the Public Service Commission is aware, they are likely to have a non-zero value in the relatively near future.

These considerations have led to the development of appliance and building standards and to utility demand-side management (DSM) programs. It is clear that rate design cannot induce sufficient conservation by itself, but it has at least some impact in increasing the amount of cost-effective conservation that is pursued. When a state is implementing energy efficiency programs, high customer charges create dueling incentives for the customer that reduce program participation and require the utility to spend more money to obtain the same participation (to overcome the fact that fixed charges cannot be saved by the customer). If higher customer charges are approved, then, energy efficiency policy is being conducted as if driving with one foot on the gas and the other on the brake.

Q. Is discouraging conservation in the public interest?

A. No. Discouraging conservation is not in the public interest. Current energy prices do not convey all necessary information to customers about future prices. It is difficult to make a good investment decision in a building that lasts 50 years or an appliance that will be around for 20 years. In fact, reducing gas demand – for example by reducing demand for electricity since gas in the marginal fuel during large portions of the year – is likely to reduce gas prices by reducing the need to drill for higher cost gas.

A comprehensive 2005 study on the relationship between gas demand and gas prices was prepared by the Lawrence Berkeley Laboratory (LBL Study). It conducts a literature review of a large number of studies by a variety of entities (including the American Council for an Energy Efficient Economy, the Energy Information Administration, the Union of Concerned Scientists, and the Tellus Institute) and conducts some independent energy modeling to identify and quantify this impact. The LBL Study found that each 1 percent reduction in gas demand reduces gas prices by 0.8 percent to 2 percent in most of the cited studies reviewed by LBL. (R. Wiser, M. Bollinger, and M. St. Clair, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency," LBNL-56756, January 2005).

We have been facing volatility in energy prices ever since 2000-2001, even if the volatility is muted by the shale gas boom. There is the looming possibility of carbon emission-related charges. A consistent policy of encouraging conservation can reduce both the severity of price excursions to society as a whole (by reducing demand and thereby lessening imbalances that create high prices) and the impacts of these price excursions and any carbon-related charges on individual consumers (who would be less exposed to the high prices if they had previously invested in conservation. Hence, conservation thus has a valuable hedging benefit. It makes sense that Wisconsin state law places energy conservation and efficiency at the top of the priority list of options to meet energy demands (Wisconsin Statutes Sec. 1.12(4))

2. Fixed Charges Blunt Conservation Policy and Raise Usage

Q. Will you explain how fixed charges are likely to increase usage?

A. There are two ways to look at this issue, which we will do schematically and illustratively. The first consideration is that the simple payback on a given conservation measure is worsened. The second consideration is that consumption will increase because of the elasticity of total demand.

Q. Can you explain what you mean when you say that the simple payback on a given conservation measure is worsened?

A. Sure. While MGE shows relatively small impacts on the simple payback for conservation due to its rate design proposals, (MGE Response to City of Madison Data Request No. MAD-21, PSC REF#: 214681, and MAD-25, PSC REF#: 214683), the Commission must remember that this is just the first installment.

Assume we have an energy efficiency program that is cost-effective to the consumer with a simple payback of 4 years under current rate design. That program has a payback of 4.3 years with MGE's 2015 rates, but its future policy will make the conservation less cost-effective to consumers, raising the payback to 7.7 years under its originally proposed 2016 rates and 15.4 years under its proposed 2017 rates. Essentially, conservation will grind to a halt.

If conservation programs are to be implemented, subsidies will need to increase or performance will be reduced or both. MGE is well aware of this, having worked to develop a pilot program on how to redesign energy efficiency programs in a fixed rate environment. As stated in PSCW Supplemental Memorandum dated June 27, 2014 for the Commission agenda (PSC REF#: 212707, page 4):

> On June 22, 2014, staff of the Public Service Commission noted that the Wisconsin Department of Administration and the Public Service Commission applied for an award from the National Governor's Association to implement a behavioral pilot to explore how to incent energy efficiency and demand response under a rate structure providing more revenue through fixed rates. Wisconsin will host an NGA retreat in August to provide assistance in planning the pilot program to incent energy efficiency and demand response. The pilot program will focus on commercial customers in the Madison Gas and Electric Company territory. A potential funding source of this pilot is the Focus undesignated fund.

We understand that the Commission approved this program at its meeting on July 10, 2014 (PSC REF#: 210465). Essentially, MGE is proposing that state policy should give with one hand and take away with the other, and this is why increasing customer charges to reduce energy charges is wasteful of government and ratepayer money.

Q. Will you discuss how the elasticity of demand will increase energy use with higher customer charges?

A. The replacement of variable rates with fixed rates will cause electricity consumption to increase. The amount depends on the elasticity of demand, which is relatively low in the short-run, but may be higher in the longer term, when new investments are made – particularly with efficiency programs supporting them. Contributing factors are the extent to which usage is driven by average versus incremental rates and whether small customers have lower elasticity than large ones.

While customers look at total bills, when they make efforts to conserve and see little benefit (or when they use more energy and see little cost), the incremental rates are important. In the case of major increases to customer charges, the incremental rates will ultimately drive conservation investments and have long-run effects. This figure depends on the elasticity of demand – the amount by which consumption changes for a change in the incremental price of electricity. We used a range for an intermediate-term elasticity range of 0.075 to 0.3, with a midpoint of -0.15). An elasticity of -0.075 to -0.3 means that usage would increase between 0.75% and 3% if there were a price reduction of 10%. A recent paper using data from British Columbia Hydro (Michael Li, Ren Orans, Jenya Kahn-Lang, and C. K. Woo,"Are Residential Customers Price-Responsive to an Inclining Block Rate? Evidence from British Columbia, Canada," June, 2014) shows price elasticity resulting from a tiered rate design of -0.08 to -0.18, figures in the middle of my larger range, with higher elasticities for space heating users and for larger customers in general.

Q. How much could MGE's consumption increase with its 2016 proposed $49 customer charge?

A. Exhibit Ex.-City of Madison-Marcus-13 estimates changes in residential consumption that could result from the 2016 customer charge increase. We estimate that the 49% reduction in the variable rate in 2016 could raise consumption in the short run by 2 to 13% depending on the elasticity and the percentage of average rate in the elasticity. All of these figures assume that use by customers under 200 kWh per month is inelastic and that elasticity increases linearly from 200-400 kWh per month.. For reference, current levels of residential consumption are 784,000 MWh.

E. MGE's Increases to Customer Charges Directly Conflict with the Goals and Plans of the City of Madison.

Q. Are you aware of the City of Madison's Sustainability Plan?

A. Yes. I have reviewed the Plan and its Supplement, which are attached to my testimony as exhibits Ex.-City of Madison-Marcus-14 and Ex.-City of Madison-Marcus-15.

Q. Is the MGE proposal consistent with the City's Sustainability Plan?

A. No, not at all. The City's plan sets out strong goals related to moving to sustainable energy use in the city, including a goal of obtaining 25% of energy needs from clean energy supplies by 2025. See, for example, pages 32-39 of the Plan and pages 32-42 of the Supplement. The MGE proposal will make solar power and other distributed, clean energy, much less likely by making conservation and customer-owned generation far less cost-effective. Thus, the MGE proposal is directly contrary to, and works against, the City's Sustainability Plan.

Q. Are you aware of the City of Madison RES-13-00828, legislative file 31054, a resolution enacted on October 30, 2013 declaring the City's intention to adopt an equity impact model?

A. Yes, I have reviewed the resolution. A copy of it is attached to my testimony as exhibit Ex.-City of Madison-Marcus-16.

Q. What would be the result of applying an Equity Impact Model to the MGE rate proposal?

A. The MGE proposal will negatively impact equity in the City of Madison. As I noted earlier, this proposal is likely to harm those of low income, and benefit those of high income. There is a strong correlation between low income persons and minorities, meaning that the proposal will negatively impact minority communities in Madison. This MGE proposal will move the City of Madison in exactly the opposite direction that the City wishes to go.

F. Fixed Charges and Competition

Q. Do rates in competitive electricity markets rely more heavily on customer charges to recover costs?

A. The shift in competitive electricity markets in other regions that MGE notes tend toward increased reliance on volumetric, rather than fixed pricing for generation and transmission services. In a report to NARUC, Frederick Weston of the Regulatory Assistance Project, noted:

> Perhaps the most interesting, and most apposite, example of pricing in a competitive market is that of the electric generation sector in those states that have restructured their industries. Here we find an industry in which a high proportion of costs are fixed, but yet are recovered in prices per unit of output, kilowatt-hours.

("Charging for Distribution Utility Services: Issues in Rate Design", Frederick Weston, the Regulatory Assistance Project, Report to NARUC, December 2000, p. 19.)

If the goal of the rate structure is to seek efficiency through replicating the conditions of a competitive market, high fixed charges are counterproductive. In competitive markets, goods and services are almost invariably priced on a unit basis. Customers pay when they consume a product, they do not normally pay for the ability to consume it.

Q. Does MGE Risk losing commercial customers to regions with rate structures reflecting competition?

A. It is not clear from MGE's testimony what customers are likely to move, or reduce operations in Madison in the absence of a change in electricity rate structure. As I discuss above, rate structures in a competitive market would tend toward more cost recovery through volumetric, or variable, rates. This is in direct opposition to MGE's proposed structural changes.

MGE does note in its annual report that the local economy is strong. The Madison area is the fifth best U.S. city for high-tech jobs, Promega has opened a bio-manufaturing facility in their service territory, and Epic Systems health records company has completed a $578 Million expansion, apparently with significantly increased energy use. (MGE 2013 Annual Report, www.mgeenergy.com/images/PDF/AnnualReports/AR_2013.pdf, page 5.) Neither the latest Quarterly Financial Update, nor the 2013 Annual Report indicate any concern on MGE's part regarding future growth in energy use among commercial or industrial customers.

Q. Does MGE face economic hardship with its current rate structure as a result of sales attrition due to customer efficiency investments or installation of distributed generation systems?

A. MGE is a growing, financially stable company. In their Second Quarter 2014 Financial Update for investors, MGE touts the low volatility of earnings due to their low exposure to industrial customers. (Exhibit Ex.-City of Madison-Marcus-17 contains an excerpt.) MGE's asset base has grown steadily since 2008, with growing earnings per share from at least 2009. Standard and Poors and Moody's Investor Services rate them as stable, with S&P rating their credit at AA1, and Moody's rating secured debt at Aa2.

In their 2013 Annual Report, as discussed above, MGE touts growing industrial demand in their service territory with MGE's current rate structure.

Q. Is there competition between MGE and its customers for DG installation?

A. Possibly. MGE's concern that the current rate structure cross-subsidizes customers' distributed generation, encouraging economic oversupply, are largely unfounded, and may reflect MGE's stated intent to install local renewable distributed generation itself (MGE Response to City of Madison Data Request No. MAD-12, PSC REF#: 214680). MGE's data do not allow me to compare cost implications to the general ratepayer of shifting from future customer-owned renewable resources to future MGE-owned local renewable resources. However, it is not clear that ratepayers without renewable energy systems would be better off paying for MGE-owned resources than providing rate incentives or net metering for customer-installed systems. Certainly ratepayers would have to provide MGE shareholders with much higher return than is currently provided to customer-owned systems.

G. Alternatives to Customer Charges

Q. Is a new rate structure appropriate to address MGE's net revenue attrition from renewable distributed generation incentives?

A. Not necessarily. MGE's stated concern is that the current distributed generation (DG) rate structure shifts costs among customers' by not reflecting "real economics", and growth in DG systems will exacerbate this.

Ratepayers installing DG do not receive a windfall under current rates. MGE provides an example demonstrating that current rates afford distributed renewable generation a 4.45 percent return on investment for customers. This would drop to 4.13 percent under MGE's proposed rates (MGE Response to City of Madison Data Request No. MAD-25, PSC REF#: 214683). If return on investment drove these customers' actions, they would be far better off purchasing stock in MGE, with an authorized return on equity of 10.3 percent as requested in this docket. It is far more likely that the customers with DG are "early adopters", a small percentage of customers, not driven by financial considerations. This population is unlikely to grow significantly with such low returns, particularly with the market barriers that exist for customer-based renewable generation. (Weston at pp. 7-8.)

The City of Madison notes that MGE plans, as a bill insert states, "to deploy even more local renewable resources on behalf of everyone in our community" (MAD-12, PSC REF#: 214680). While MGE's proposal protects customers who have already installed renewable energy systems, it would reduce the financial incentives for new customer-owned systems. It is not clear that the cost of energy from renewable energy systems owned by MGE would be significantly lower.

Current rates, based on embedded costs, are unlikely to be good benchmarks for evaluating the value of distributed generation. MGE suggests that current net energy metering rates (NEM) allow customers to avoid paying the costs of existing infrastructure (Direct-MGE-Bollom-20). However, the long-run incremental capital costs and operating expenses, which DG helps to defer, may well be much closer to the NEM than MGE is arguing. MGE has not made its case.

General rate design should be driven by long-term policy goals of the regulatory commission, including fair return to the utility. Distributed Generation incentives are a separate issue, for which PSCW has been developing tools, such as an evaluation methodology.

Q. How do you recommend PSCW proceed to address MGE's DR rate concerns?

A. On April 1, 2014 the Minnesota Public Service Utilities Commission, in Docket No. E-999/M-14-65, entered an order approving a "Distributed Solar Value Methodology" for valuing the contribution of solar DG to the utility system. (Ex-City of Madison-Marcus-18.) The Minnesota Department of Commerce submitted the final "Minnesota Value of Solar: Methodology" to the Public Service Utilities Commission the following day. (Ex-City of Madison-Marcus-19.) Integral to that methodology is the use of avoided incremental capital costs of generation, transmission and distribution to value the energy provided, along with future variable costs, along with internalizing external benefits and costs. MGE's rate design policy assumes that all demand-related distribution, transmission, and generation-related costs are fixed, and the marginal costs for all of these items are zero. Such a decision is highly inappropriate. Even worse, MGE does not even tell the Commission that that is what it is assuming by claiming that all non-fuel costs on the entire system are fixed. The PSCW should follow the Minnesota Public Service Commission's lead and require either PSC staff or MGE to conduct an evaluation using the Distributed Solar Value Methodology to propose a cost-beneficial incentive level for customer-owned solar facilities. That basic methodology could also be adapted to other distributed renewable technologies. It may also be used to evaluate the economic desirability of future proposed MGE-owned renewable facilities.

Q. Do you recognize that if MGE is successful with conservation, solar, or demand side programs that it may need more revenue to cover its costs?

A. Yes. However, as discussed below, decoupling and other similar methods can solve this problem for MGE without the extremely drastic effects on ratepayers that it is currently proposing.

Q. What other methods are available to PSCW to mitigate any lost net revenue to MGE from DG and conservation?

A. Over a dozen states have adopted mechanisms for mitigating a utility's loss in net income from sales declines due to efficiency and/or distributed generation. These approaches avoid the conflict between large customer charges and policy goals of encouraging efficient use of energy, developing renewable sources of energy and protecting low income customers from high rates.

Other states have adopted either revenue regulation (revenue decoupling) or a "lost revenue adjustment mechanisms (LRAM)" (Weston at 46).

The processes for implementing these rate tools are similar. For decoupling, the regulator determines a utility's allowed revenue for a defined period. At the end of the period, the utility's actual revenue is compared to the allowed revenue. The regulator authorizes a small credit or surcharge, normally on a per-kWh basis, to refund the surplus or recover the deficiency. This procedure can take into account either decreased or increased energy sales.

For the LRAM, a utility margin per kWh is computed in a general rate case. This can be either a gross margin or a distribution margin, excluding power supply-related costs. For each kWh of conservation program savings or DG-driven sales reduction, the utility is allowed subsequent recovery of the lost margin through a tariff rider, until the next ratecase. The next case's assumptions take the adjusted sales volume into account in setting rates. This procedure only works with decreased sales from specified programs. (Id. at 47.)

By decoupling the impact of DG and conservation-caused sales reductions from utility net income, these options allow rate designs that can promote long-range policy goals and maintain the utility's financial health.

Q. Are there any other rate design alternatives that the Commission should consider in the longer term even if it wants to put the brakes on DG, in lieu of massive increases to the customer charge and potential residential demand charges?

A. Yes. If distributed generation is the "problem" (a point of which I am not convinced) then less intrusive measures can deal with it without creating collateral damage among a large number of MGE's residential customers. Examples of such measures are:

- Minimum bills (where a customer must pay a fixed rate that includes, for example 100-150 kWh of non-generation costs, a level below all but the smallest apartments, but allowing some cost recovery from vacant homes and distributed generation customers).

- Changing net metering so that any exports only are assigned transmission and generation rate savings and not distribution savings.
- Going one step further and establishing bi-directional distribution rates (where a customer pays a distribution charge for all energy imported or exported).

The latter two options require different metering than is currently available in MGE's service area, and would therefore not be recommended unless the utility were to pursue Advanced Metering Infrastructure ("smart meters") on a global basis.

Q. Are you recommending adoption of any of these options now?

A. No. All I am pointing out is that before MGE and the Commission rush all too hastily into a regressive plan to harm poor people and small users with fixed charges that have no cost basis, it should actually analyze the problem it is trying to solve and examine other alternatives that might be less drastic.

Otherwise MGE's cure is almost certain to be worse than the disease and is more likely to harm the customers it is attempting to "protect."

An elderly person in a small apartment might pay somewhat higher rates if (under the utility's stereotype) rich people install photovoltaics and save more money than they are worth. MGE is allegedly trying to prevent that.

But if prevention comes with a $19 – or worse, $48 or $69 customer charge (as the company proposed for 2016-2017 in its original rate case), we must ask, "Is it worth it, even assuming for the sake of argument that the utility is right to worry about solar?"

Solar has a return to the customer of only 4.45% according to MGE. The hundreds of extra dollars in enormous customer charges that this hypothetical customer would have to pay would almost certainly cost far more and impose more hardship than any possible rate increase from solar and conservation.

It would be imprudent to engage in a massive social experiment, as MGE proposes with its extreme customer charges that could make rates unaffordable for people on fixed incomes. Arrearages, disconnections, and the end of universal service would be far worse than if ratepayers paid a few extra dollars in the event that a few customers might decide to earn a 5% rate of return or less on photovoltaics. MGE shareholders would clearly be better off nipping the competition in the bud before it spreads. But MGE has not made the case that its many low-use ratepayers would not be better off with the status quo in lieu of paying several hundred extra dollars per year to follow MGE's misguided pursuit of so-called "economic efficiency." As an economist, I will tell you that if the goal of recovering fixed costs in fixed charges causes people on fixed or minimum wage incomes to choose between eating, making their rent, and paying $19, $48, or $69 customer charges, then economic theory needs to be jettisoned. Even if the company's economists and engineers might think high fixed charges are both good for MGE shareholders and intellectually elegant, the real world is a place in which many real people are trying to survive on too little money, not a "special case" to be ignored.

Q. Will you summarize your recommendation?

A. I see no reason to raise customer charges based on policy. The utility's proposals for future years – what it wants to advance if it gets its way in this rate case – are simply extreme and frightening ways to subsidize big users with rates that are not based on cost at all. If any customer charge increase is authorized in this case, it should be no more than the percentage of overall rate increases for residential and small commercial customers.

Q. Does this complete your testimony?

A. Yes, it does. Thank you.